Oklahoma Department of Environmental Quality
Air Quality Division

BART Application Analysis **January 19, 2010**

COMPANY:	**AEP- Public Service Company of Oklahoma**
FACILITY:	**Southwestern Power Station**
FACILITY LOCATION:	**Caddo County, Oklahoma**
TYPE OF OPERATION:	**(1) 332 MW Steam Electric Generating Unit**
REVIEWER:	**Phillip Fielder, Senior Engineering Manager** **Lee Warden, Engineering Manager**

I. PURPOSE OF APPLICATION

On July 6, 2005, the U.S. Environmental Protection Agency (EPA) published the final "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations" (the "Regional Haze Rule" 70 FR 39104). The Regional Haze Rule requires certain States, including Oklahoma, to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I Areas. The Regional Haze Rule requires states to submit a plan to implement the regional haze requirements (the Regional Haze SIP). The Regional Haze SIP must provide for a Best Available Retrofit Technology (BART) analysis of any existing stationary facility that might cause or contribute to impairment of visibility in a Class I Area.

II. BART ELIGIBILITY DETERMINATION

BART-eligible sources include those sources that:

(1) have the potential to emit 250 tons or more of a visibility-impairing air pollutant;
(2) were in existence on August 7, 1977 but not in operation prior to August 7, 1962; and
(3) whose operations fall within one or more of the specifically listed source categories in 40 CFR 51.301 (including fossil-fuel fired steam electric plants of more than 250 mmBtu/hr heat input and fossil-fuel boilers of more than 250 mmBtu/hr heat input).

Southwestern Unit 3 is a fossil-fuel fired boiler with heat inputs greater than 250-mmBtu/hr. The unit was in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Based on a review of existing emissions data, the unit has the potential to emit more than 250 tons per year of NO_X, a visibility impairing pollutant. Therefore, Southwestern Unit 3 meets the definition of a BART-eligible source.

BART is required for any BART-eligible source that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I Area.

DEQ has determined that an individual source will be considered to "contribute to visibility impairment" if emissions from the source result in a change in visibility, measured as a change in deciviews (Δ-dv), that is greater than or equal to 0.5 dv in a Class I area. Visibility impact modeling conducted by AEP-PSO determined that the maximum predicted visibility impacts from Southwestern Unit 3 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains Class I Area. Therefore, Southwestern Unit 3 was determined to be BART applicable sources, subject to the BART determination requirements.

III. DESCRIPTION OF BART SOURCES

Baseline emissions from Southwestern Unit 3 were developed based on an evaluation of actual emissions data submitted by the facility pursuant to the federal Acid Rain Program. In accordance with EPA guidelines in 40 CFR 51 Appendix Y Part III, emission estimates used in the modeling analysis to determine visibility impairment impacts should reflect steady-state operating conditions during periods of high capacity utilization. Therefore, baseline emissions (lb/hr) represent the highest 24-hour block emissions reported during the baseline period. Baseline emission rates (lb/mmBtu) were calculated by dividing the maximum hourly mass emission rates for the boiler by the boiler's heat input at that emission rate.

Table 1: Southwestern Power Station- Plant Operating Parameters for BART Evaluation

Parameter	**Southwestern Unit 3**	
Plant Configuration	Natural Gas-Fired Boiler	
Gross Output (nominal)	332 MW	
Maximum Input to Boiler	3,290 mmBtu/hr	
Primary Fuel	Natural gas	
Existing NO_X Controls	None	
Existing PM_{10} Controls	NA	
Existing SO_2 Controls	NA	
Baseline Emissions Pollutant	**Baseline Actual Emissions**	
	lb/hr	**lb/mmBtu**
NO_X	**3,705**	**1.126**
PM_{10}	**24.5**	**0.007**
SO_2	**1.97**	**0.0006**

IV. BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Guidelines for making BART determinations are included in Appendix Y of 40 CFR Part 51 (Guidelines for BART Determinations under the Regional Haze Rule). States are required to use the Appendix Y guidelines to make BART determinations for fossil-fuel-fired generating plants having a total generating capacity in excess of 750 MW. The BART determination process described in Appendix Y includes the following steps:

Step 1. Identify All Available Retrofit Control Technologies.
Step 2. Eliminate Technically Infeasible Options.
Step 3. Evaluate Control Effectiveness of Remaining Control Technologies.
Step 4. Evaluate Impacts and Document the Results.
Step 5. Evaluate Visibility Impacts.

Because the unit fires natural gas, emissions of sulfur dioxide (SO_2) and particulate matter (PM) are minimal. There are no SO_2 or PM post-combustion control technologies with a practical application to natural gas-fired boilers. BART is good combustion practices. A full BART analysis was conducted for NO_X.

Table 2: Proposed BART Controls and Limits

Unit	NO_X BART Emission Limit	BART Technology
Southwestern Unit 3	0.45 lb/mmBtu (30-day average)	LNB/OFA

A. NO_X

IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Potentially available control options were identified based on a comprehensive review of available information. NO_X control technologies with potential application to Southwestern Unit 3 are listed in Table 3.

Table 3: List of Potential Control Options

Control Technology
Combustion Controls
Burners Out of Service (BOOS)
Low NO_X Burners and Overfire Air (LNB/OFA)
Induced Flue Gas Recirculation (FGR)
Post Combustion Controls
Selective Catalytic Reduction (SCR)

In support of the Regional Haze Rule, EPA also prepared a cost-effectiveness analysis for retrofit control technologies on oil- and gas-fired units. EPA's analysis concluded that, although a number of oil- and gas-fired units could make significant cost-effective reductions in NO_X emissions using currently available combustion control technologies, for a number of units the use of combustion controls did not appear to be cost effective. As a result, EPA determined that it would be inappropriate to establish a general presumption regarding likely BART limits for oil- and natural gas fired units.

ELIMINATE TECHICALLY INFEASIBLE OPTIONS (NO_X)

Combustion Controls:

Burners Out of Service (BOOS)

This option involves shutting off selected burners, resulting in reduced fuel usage and therefore lower emissions. This option would essentially reduce the maximum firing rate of the boiler, and places a load limit on the unit. AEP-PSO estimates that NO_X emissions can be reduced 20-25%. Implementation of this option will reduce the maximum firing rate of the unit, thereby creating an artificial load limit. Although this does not preclude this option from being physically implemented, the resulting load limits would effectively result in the shutdown of the units. As a result, this option is considered technically infeasible.

Induced Flue Gas Recirculation (IFGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the heater or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces thermal NO_X formation. When operated without additional controls, the average NO_X control efficiency range for FGR is 30 percent to 40 percent. This control option would also place load limits on the boiler and also call for plant component upgrades. As with the Burners Out Of Service, IFGR is considered technically infeasible as a standalone NO_X control for Southwestern Power Station Unit 3.

Low NO_X burners (LNB)/ Over Fire Air (OFA)

Low NO_X burners (LNB) limit NO_X formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. Over Fire Air (OFA) allows for staged combustion. Staging combustion reduces NO_X formation with a cooler flame in the initial stage and less oxygen in the second stage.

LNB/OFA emission control systems have been installed as retrofit control technologies on existing natural gas-fired boilers. Boilers of the size and age of the Southwestern Unit would be expected to achieve an average emission reduction in the range of 30% to 60% from baseline depending on the baseline emission rate and boiler operating conditions. Southwestern Unit 3 does not operate as base load units. The unit has historically operated as a "peaking unit" responding to increased demand for electricity. While technically feasible, LNB/OFA may not be as effective under all boiler operating conditions, especially during load changes and at low and high operating loads.

Post Combustion Controls:

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting ammonia into boiler flue gas in the presence of a catalyst to reduce NO_X to N_2 and water. Anhydrous ammonia injection systems may be used, or ammonia may be generated on-site from a urea feedstock.

SCR has been installed as NO_X control technology on existing gas-fired boilers. Based on emissions data available from the EPA Electronic Reporting website, large gas-fired boilers (with heat inputs above approximately 1,000 mmBtu/hr) have achieved actual long-term average NO_X emission rates in the range of approximately 0.02 to 0.05 lb/mmBtu. Several design and operating variables will influence the performance of the SCR system, including the volume, age and surface area of the catalyst (e.g., catalyst layers), uncontrolled NO_X emission rate, flue gas temperature, and catalyst activity.

Based on emission rates achieved in practice at existing gas-fired units, and taking into consideration long-term operation of an SCR control system (including catalyst plugging and deactivation) and the fact that the Southwestern boiler typically operates as a peaking unit, it is anticipated that SCR could achieve a controlled NO_X emission rate of 0.05 lb/mmBtu (30-day rolling average) on Southwestern Unit 3.

EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (NO_X)

Table 4: Technically Feasible NO_X Control Technologies- Southwestern Station

Control Technology	Southwestern Unit 3 Approximate NO_X Emission Rate (lb/mmBtu)
LNB/OFA + SCR	0.05
LNB/OFA	0.45
Baseline[1]	1.126

[1]Baseline emissions for modeling are based on the maximum 24-hour emission rate over the baseline period. Baseline emissions for cost effectiveness calculations were based on the annual average emission rate of 0.57 lb/mmBtu.

EVALUATE IMPACTS AND DOCUMENT RESULTS (NO_X)

AEP-PSO evaluated the economic, environmental, and energy impacts associated with the proposed control options. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual. Major equipment costs were developed based on costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit Southwestern Unit 3 with the control technologies. Fixed and variable O&M costs were developed for each control system. Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent (e.g., ammonia) and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with operation of the new control technology. The capital recovery factor used to estimate the annual cost of control was based on a 8% interest rate and a control life of 20 years. Annual operating costs and annual emission reductions were calculated assuming a capacity factor of 26%.

Table 5: Economic Cost

Cost	Option 1: LNB/OFA	Option 2: LNB/OFA +SCR
Control Equipment Capital Cost ($)	$3,000,000	$68,968,400
Capital Recover Factor ($/Yr)	$305,557	$7,024,584
Annual O&M Costs ($/Yr)	$120,000	$3,682,650
Annual Cost of Control ($)	$425,557	$10,707,234

Table 6: Environmental Costs per Boiler

	Baseline	LNB/OFA	LNB/OFA +SCR
NO_X Emission Rate (lb/mmBtu)	0.57	0.45	0.05
Annual NO_X Emission (TPY)	2,136	1,686	187
Annual NO_X Reduction (TPY)	--	450	1,949
Annual Cost of Control	--	$425,557	$10,707,234
Cost per Ton of Reduction	--	$946	$5,494
Incremental Cost per ton of Reduction	--	--	$6,859

B. VISIBILITY IMPROVEMENT DETERMINATION

The fifth of five factors that must be considered for a BART determination analysis, as required by a 40 CFR part 51- Appendix Y, is the degree of Class I area visibility improvement that would result from the installation of the various options for control technology. This factor was evaluated for the Southwestern Power Station by using an EPA-approved dispersion modeling system (CALPUFF) to predict the change in Class I area visibility. The Division had previously determined that the Southwestern Power Station was subject to BART based on the results of initial screening modeling that was conducted using current (baseline) emissions from the facility. The screening modeling, as well as more refined modeling conducted by the applicant, is described in detail below.

Wichita Mountain Wildlife Refuge, Caney Creek, Upper Buffalo and Hercules Glade are the closest Class I areas to the Southwestern Power Station, as shown in Figure 1 below.

Only those Class I areas most likely to be impacted by the Southwestern Power Station were modeled, as determined by source/Class I area locations, distances to each Class I area, and professional judgment considering meteorological and terrain factors. It can be reasonably assumed that areas at greater distances and in directions of less frequent plume transport will experience lower impacts than those predicted for the four modeled areas.

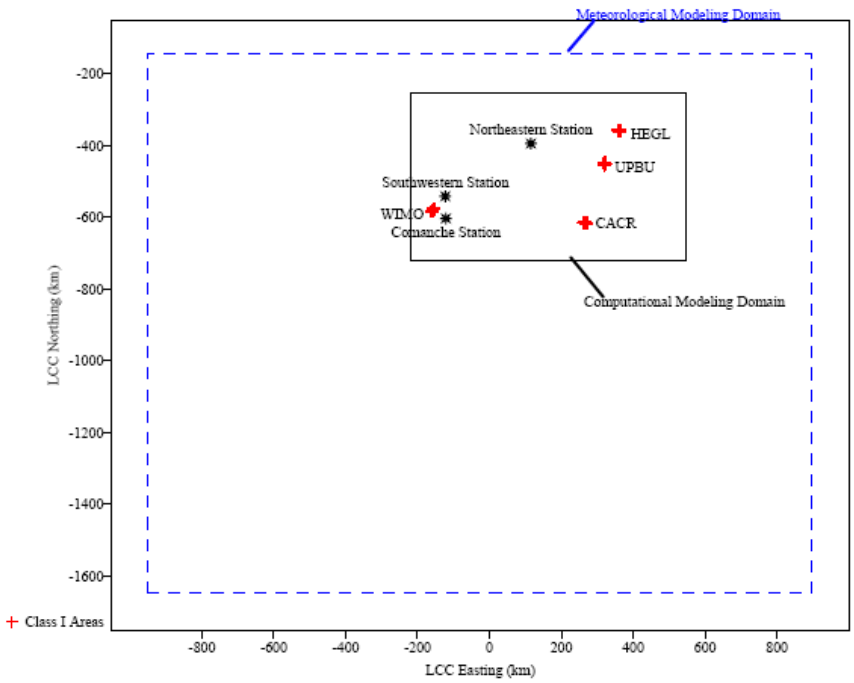

Figure 1: Plot of Facility location in relation to nearest Class I areas

REFINED MODELING:

Because of the results of the applicants screening modeling for the Southwestern Power Station, AEP-PSO was required to conduct a refined BART analysis that included CALPUFF visibility

modeling for the facility. The modeling approach followed the requirements described in the Division's BART modeling protocol, *CENRAP BART Modeling Guidelines (Alpine Geophysics, December 2005)* with refinements detailed the applicants CALMET modeling protocol, *CALMET Data Processing Protocol (Trinity Consultants, August 2008)*

CALPUFF System

Predicted visibility impacts from the Southwestern Power Station were determined with the EPA CALPUFF modeling system, which is the EPA-preferred modeling system for long-range transport. As described in the EPA Guideline on Air Quality Models (Appendix W of 40 CFR Part 51), long-range transport is defined as modeling with source-receptor distances greater than 50 km. Because most modeled areas are located more than 50 km from the sources in question and the Wichita Mountains are within 44 km, the CALPUFF system was appropriate to use.

The CALPUFF modeling system consists of a meteorological data pre-processor (CALMET), an air dispersion model (CALPUFF), and post-processor programs (POSTUTIL, CALSUM, CALPOST). The CALPUFF model was developed as a non-steady-state air quality modeling system for assessing the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal.

CALMET is a diagnostic wind model that develops hourly wind and temperature fields in a three-dimensional, gridded modeling domain. Meteorological inputs to CALMET can include surface and upper-air observations from multiple meteorological monitoring stations. Additionally, the CALMET model can utilize gridded analysis fields from various mesoscale models such as MM5 to better represent regional wind flows and complex terrain circulations. Associated two-dimensional fields such as mixing height, land use, and surface roughness are included in the input to the CALMET model. The CALMET model allows the user to "weight" various terrain influences parameters in the vertical and horizontal directions by defining the radius of influence for surface and upper-air stations.

CALPUFF is a multi-layer, Lagrangian puff dispersion model. CALPUFF can be driven by the three-dimensional wind fields developed by the CALMET model (refined mode), or by data from a single surface and upper-air station in a format consistent with the meteorological files used to drive steady-state dispersion models. All far-field modeling assessments described here were completed using the CALPUFF model in a refined mode.

CALPOST is a post-processing program that can read the CALPUFF output files, and calculate the impacts to visibility.

All of the refined CALPUFF modeling was conducted with the version of the CALPUFF system that was recognized as the EPA-approved release at the time of the application submittal. Version designations of the key programs are listed in the table below.

Table 7: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.8	070623
CALPOST	5.51	030709

Meteorological Data Processing (CALMET)

As required by the Division's modeling protocol, the CALMET model was used to construct the initial three-dimensional wind field using data from the MM5 model. Surface and upper-air data were also input to CALMET to adjust the initial wind field.

The following table lists the key user-defined CALMET settings that were selected.

Table 8: CALMET Variables

Variable	Description	Value
PMAP	Map projection	LCC (Lambert Conformal Conic)
DGRIDKM	Grid spacing (km)	4
NZ	Number of layers	12
ZFACE	Cell face heights (m)	0, 20, 40, 60, 80, 100, 150, 200, 250, 500, 1000, 2000, 3500
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model outputs	14 km (MM5 data)
RMAX1	Maximum radius of influence (surface layer, km)	20 km
RMAX2	Maximum radius of influence (layers aloft, km)	50 km
TERRAD	Radius of influence for terrain (km)	10 km
R1	Relative weighting of first guess wind field and observation (km)	10 km
R2	Relative weighting aloft (km)	25 km

The locations of the upper air stations with respect to the modeling domain are shown in Figure 2.

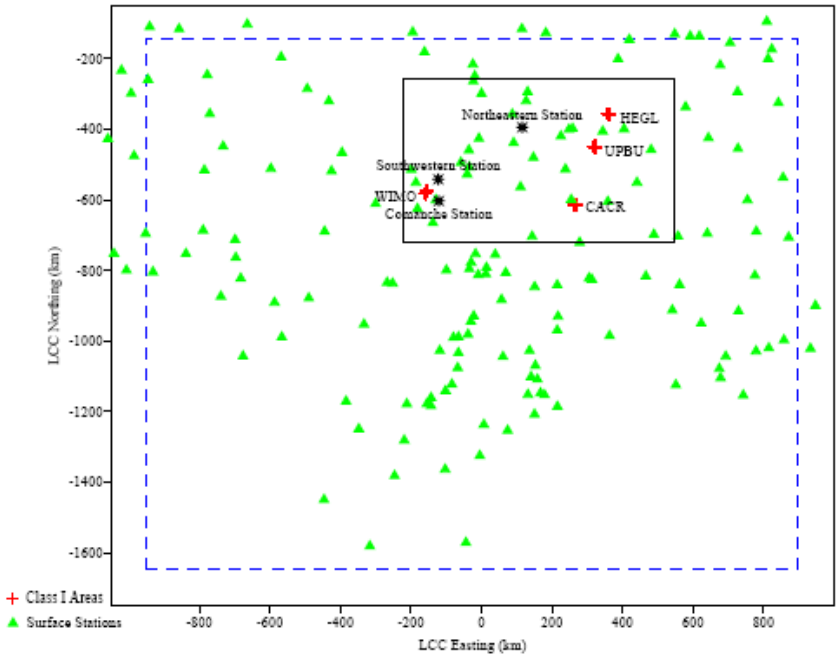

Figure 2: Plot of surface station locations

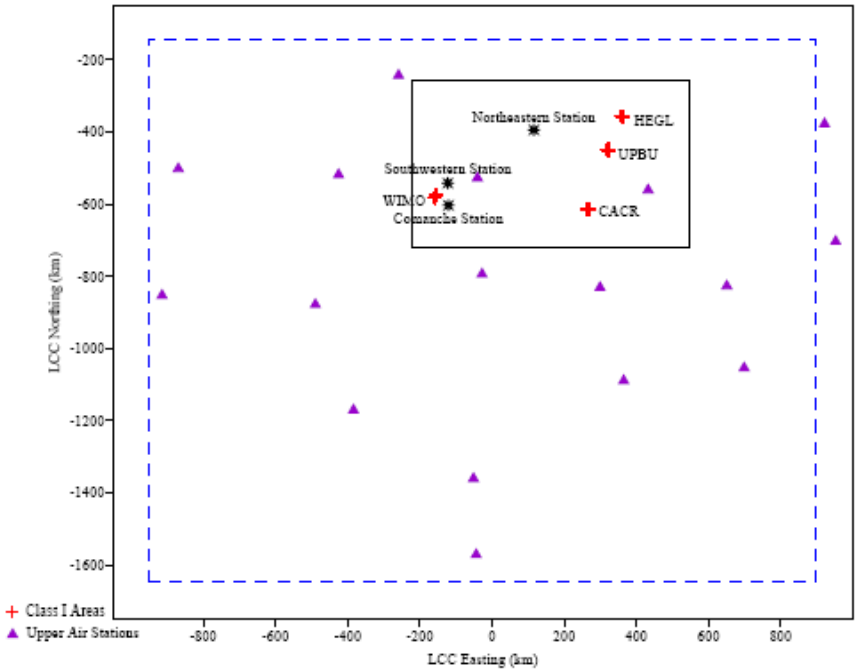

Figure 3: Plot of upper air station locations

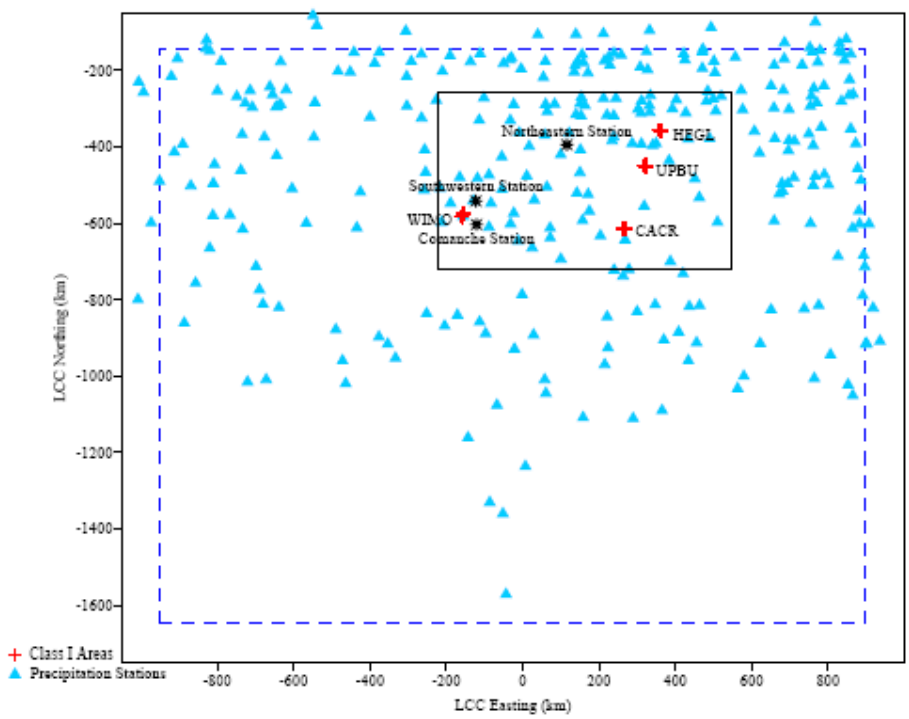

Figure 4. Plot of precipitation observation stations

CALPUFF Modeling Setup

To allow chemical transformations within CALPUFF using the recommended chemistry mechanism (MESOPUFF II), the model required input of background ozone and ammonia. CALPUFF can use either a single background value representative of an area or hourly ozone data from one or more ozone monitoring stations. Hourly ozone data files were used in the CALPUFF simulation. As provided by the Oklahoma DEQ, hourly ozone data from the Oklahoma City, Glenpool, and Lawton monitors over the 2001-2003 time frames were used. Background concentrations for ammonia were assumed to be temporally and spatially invariant and were set to 3 ppb.

Latitude and longitude coordinates for Class I area discrete receptors were taken from the National Park Service (NPS) Class I Receptors database and converted to the appropriate LCC coordinates.

CALPUFF Inputs- Baseline and Control Options

The first step in the refined modeling analysis was to perform visibility modeling for current (baseline) operations at the facility. Emissions of NO_X for the baseline runs were established based on CEM data and maximum 24-hour emissions averages for years 2001 to 2005.

Baseline source release parameters and emissions are shown in the table below, followed by tables with data for the various control options.

Table 9: Baseline Source Parameters

Parameter	Southwestern Unit 3 Natural Gas-Fired
Heat Input (mmBtu/hr)	3,290
Base Elevation (m)	371
Stack Height (m)	43
Stack Diameter (m)	4.27
Stack Temperature (K)	408
Exit Velocity (m/s)	16.26
SO2 Emissions (lb/mmBtu)	0.0006
SO2 Emissions (TPY)	8.63
NOX Emissions[1] (lb/mmBtu)	1.26
NOX Emissions TPY	16227.9
PM_{10} Fine Emissions[2] (lb/mmBtu)	0.00175
PM_{10} Fine Emissions (TPY)	6.13
PM_{10} Coarse Emissions (lb/mmBtu)	0.00525
PM_{10} Coarse Emissions (TPY)	18.39

[1]Baseline NOx emissions were based on the maximum 24-hr average emission rate (lb/hr) reported by the unit during the baseline period 2003-2005. Baseline emissions data were provided by AEP-PSO. Baseline emission rates (lb/mmBtu) were calculated by dividing the maximum 24-hr lb/hr emission rate by the maximum heat input to the boiler at that emission rate.
[2]PM emissions are based on AP-42 emission factors for natural gas combustion and NPS speciation factors for (filterable and condensable).

Visibility Post-Processing (CALPOST) Setup

The changes in visibility were calculated using Method 6 with the CALPOST post-processor. Method 6 requires input of monthly relative humidity factors [f(RH)] for each Class I area that is being modeled. Monthly f(RH) factors that were used for this analysis are shown in the table below.

Table 11: Relative Humidity Factors for CALPOST

Month	Wichita Mountains	Caney Creek	Upper Buffalo	Hercules Glade
January	2.7	3.4	3.3	3.2
February	2.6	3.1	3.0	2.9
March	2.4	2.9	2.7	2.7
April	2.4	3.0	2.8	2.7
May	3.0	3.6	3.4	3.3
June	2.7	3.6	3.4	3.3
July	2.3	3.4	3.4	3.3
August	2.5	3.4	3.4	3.3
September	2.9	3.6	3.6	3.4
October	2.6	3.5	3.3	3.1
November	2.7	3.4	3.2	3.1
December	2.8	3.5	3.3	3.3

EPA's default average annual aerosol concentrations for the U.S. that are included in Table 2-1 of EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program* were to develop natural background estimates for each Class I area.

Visibility Post-Processing Results

Table 12: CALPUFF Visibility Modeling Results for Southwestern Unit 3

Class I Area	2001	2002	2003	3-Year Average
	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)
Baseline				
Wichita Mountains	3.86	2.85	3.74	3.48
Scenario 2- Combustion Control- LNB/OFA				
Wichita Mountains	1.73	1.24	1.70	1.56

Modeling for SCR controls resulted in an approximately 88% reduction in visibility impairment from scenario two.

C. BART DETERMINATION

After considering: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollutant equipment in use or in existence at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility (all five statutory factors) from each proposed control technology, the Division determined BART for the unit at the Southwestern Power Station.

New LNB with OFA is determined to be BART for NOX control for Unit 3 based, in part, on the following conclusions:

1. Installation of new LNB with OFA was cost effective, with a capital cost of $3,000,000 and an average cost effectiveness of $947 per ton of NO_X removed over a twenty year operational life.

2. Combustion control using the LNB/OFA does not require non-air quality environmental mitigation for the use of chemical reagents (i.e., ammonia or urea) and there is minimal energy impact.

3. After careful consideration of the five statutory factors, especially the costs of compliance NO_X control levels on 30-day rolling averages of 0.45 lb/mmBtu for Unit 3 are justified.

4. Annual actual NO_X emission reductions from new LNB with OFA on Unit 3 are 450 tons.

LNB with OFA and SCR was not determined to be BART for NO_X control for Unit 3 based, in part, on the following conclusions:

1. The cost of compliance for installing SCR on each unit is significantly higher than the cost for LNB with OFA. Additional capital costs for SCR on Unit 3 are $65,968,400. Based on projected actual emissions, SCR could reduce overall NO_X emissions from Southwestern Unit 3 by approximately 1,441 tpy (compared to combustion controls); however, the incremental cost associated with this reduction is approximately $10,281,677 per year, or $6,859/ton.

2. Additional non-air quality environmental mitigation is required for the use of chemical reagents.

3. Operation of LNB with OFA and SCR is parasitic and requires power from each unit.

4. SCR control may not be as effective on boilers that operate as peaking units, as NO_X reduction in an SCR is a function of flue gas temperature.

The Division considers the installation and operation of the BART determined NO_X controls, new LNB with OFA, to meet the statutory requirements of BART.

V. CONSTRUCTION PERMIT

Prevention of Significant Deterioration (PSD)
Southwestern Power Station is a major source under OAC 252:100-8 Permits for Part 70 Sources. AEP-PSO should comply with the permitting requirements of Subchapter 8 as they apply to the installation of controls determined to meet BART.

The installation of controls determined to meet BART will not change NSPS or NESHAP/MACT applicability for the gas-fired units at the Southwestern Station.

VI. OPERATING PERMIT

The Southwestern Power Station is a major source under OAC 252:100-8 and has submitted an application to modify their existing Title V permit to incorporate the requirement to install controls determined to meet BART. The Permit will contain the following specific conditions:

1. Unit 3 in EUG 1 is subject to the Best Available Retrofit Technology (BART) requirements of 40 CFR Part 51, Subpart P, and shall comply with all applicable requirements including but not limited to the following: [40 CFR §§ 51.300-309 & Part 51, Appendix Y]

   a. Affected facilities. The following sources are affected facilities and are subject to the requirements of this Specific Condition, the Protection of Visibility and Regional Haze Requirements of 40 CFR Part 51, and all applicable SIP requirements:

EU ID#	Point ID#	EU Name	Heat Capacity (MMBTUH)	Construction Date
3	3	Babcock/Wilcox, RB-426	3,290	May 1967

b. Each existing affected facility shall install and operate the SIP approved BART as expeditiously as practicable but in no later than five years after approval of the SIP incorporating the BART requirements.

c. The permittee shall apply for and obtain a construction permit prior to modification of the boilers. If the modifications will result in a significant emission increase and a significant net emission increase of a regulated NSR pollutant, the applicant shall apply for a PSD construction permit.

d. The affected facilities shall be equipped with the following current combustion control technology, as determined in the submitted BART analysis, to reduce emissions of NOX to below the emission limits below:
   i. Low-NOX Burners,
   ii. Overfire Air, and

e. The permittee shall maintain the combustion controls (Low-NOX burners, overfire air) and establish procedures to ensure the controls are properly operated and maintained.

f. Within 60 days of achieving maximum power output from each affected facility, after modification or installation of BART, not to exceed 180 days from initial start-up of the affected facility the permittee shall comply with the emission limits established in the construction permit. The emission limits established in the construction permit shall be consistent with manufacturer's data and an agreed upon safety factor. The emission limits established in the construction permit shall not exceed the following emission limits:

EU ID#	Point ID#	NOX Emission Limit	Averaging Period
3	03	0.45 lb/MMBTU	30-day rolling

g. Boiler operating day shall have the same meaning as in 40 CFR Part 60, Subpart Da.

h. After installation of the BART, the affected facilities shall only be fired with natural gas.

i. Within 60 days of achieving maximum power output from the boiler, after modification of the boiler, not to exceed 180 days from initial start-up, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with BART emission limits for the affected facilities. [OAC 252:100-8-6(a)]
   i. The permittee shall conduct NOX, CO, and VOC testing on the boilers at 60% and 100% of the maximum capacity. NOX and CO testing shall also be conducted at least one additional intermediate point in the operating range.
   ii. Performance testing shall be conducted while the units are operating within 10% of the desired testing rates. A testing protocol describing how the testing will be performed shall be provided to the AQD for review and approval at least 30 days prior to the start of such testing. The permittee shall also provide notice of the actual test date to AQD.

iii. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality:

Method 1:	Sample and Velocity Traverses for Stationary Sources.
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.